anderson energy 2005 ANNUAL REPORT

COVER:

M. DARLENE WONG *Vice President Finance, Chief Financial Officer and Secretary*

J.C. ANDERSON *Chairman of the Board*

BRIAN H. DAU *President and Chief Executive Officer and Director*

INSIDE COVER:

R.T. (TIM) SWINTON *Director*

DAVID M. SPYKER *Vice President, Business Development*

VINCENT L. CHAHLEY *Director*

We brought the best together. To get the best result.

Anderson Energy Ltd. was initially established as a private company in 2002. Most of the founders of Anderson Energy Ltd. were part of the management team or board of directors of Anderson Exploration Ltd. The Company went public through a plan of arrangement with the acquisition of Aquest Energy Ltd. in September 2005. The common shares of Anderson Energy are listed on the Toronto Stock Exchange under the symbol AXL. The Company operates in Alberta and northeast British Columbia with an 84% leverage towards natural gas.

ANNUAL GENERAL MEETING The Annual General Meeting of Shareholders will be held on May 12, 2006 at 10:00 am at the Metropolitan Conference Centre, 333 – 4th Avenue S.W., Calgary Alberta.

CONTENTS:

Financial and Operating Highlights

	2005	2004	% change
FINANCIAL (thousands of dollars, except share data)			
Total oil and gas revenue	46,953	13,766	241
Oil and gas revenue, net of royalties	36,780	10,754	242
Cash flow from operations	25,455	6,216	310
Per common share (basic)	0.66	0.21	214
Per common share (diluted)	0.65	0.21	210
Earnings (loss)	731	(1,619)	145
Per common share (basic)	0.02	(0.05)	140
Per common share (diluted)	0.02	(0.05)	140
Capital expenditures	72,730	41,367	76
Corporate acquisition	80,589	–	
Debt, net of working capital	24,597	(16,719)	247
Shareholders' equity	184,069	101,308	82
Average shares outstanding *(thousands)*			
Basic	38,372	29,536	30
Diluted	39,309	29,977	31
Ending shares outstanding *(thousands)*	47,968	33,565	43
OPERATING (6 Mcf : 1 bbl conversion)			
Average daily sales			
Natural gas *(Mcfd)*	12,170	5,586	118
Light/medium crude oil *(bpd)*	154	2	7,600
NGL *(bpd)*	74	19	289
Total liquids *(bpd)*	228	21	986
Barrels of oil equivalent *(BOED)*	2,256	952	137
Average prices			
Natural gas *($/Mcf)*	9.42	6.55	44
Light/medium crude oil *($/bbl)*	54.72	55.45	(1)
NGL *($/bbl)*	58.41	46.40	26
Total liquids *($/bbl)*	55.92	47.29	18
Barrels of oil equivalent *(BOED)*	56.46	39.50	43
Reserves			
Natural gas *(MMcf)*			
Proved	51,907	13,676	280
Proved plus probable	101,118	28,729	252
Crude oil and NGL *(Mbbls)*			
Proved	934	99	843
Proved plus probable	1,483	280	430
Undeveloped land *(thousands of acres)*			
Gross	492	273	80
Net	247	150	65
Net asset value *($/share)*	6.22	3.02	106

	2005 Gross	2005 Net	2004 Gross	2004 Net
Wells drilled *(gross/net)*				
Gas	103	54.0	45	32.6
Oil	5	2.8	4	3.4
Dry	10	6.3	6	5.2
Total	118	63.1	55	41.2

To our Shareholders,

This is Anderson Energy's first annual report as a public company. Anderson Energy Ltd. ("Anderson Energy" or "the Company") was a privately held company from April 2002 until September 2005. The Company was formed in 2002. Most of the management team and board of directors were previously involved with Anderson Exploration Ltd.

We are very pleased to report a 106% increase in net asset value ("NAV") per share from $3.02 per share at December 31, 2004 to $6.22 per share at December 31, 2005. In 2005, the Company acquired Aquest Energy Ltd. ("Aquest Energy") and became a public oil and gas company which commenced trading on the TSX on September 7, 2005. Other notable achievements in 2005 included the completion of the earning phase of the Calpine Natural Gas Trust ("CNGT") farm-in agreement on March 10, 2005, the completion of a $28.3 million financing on August 4, 2005 and the drilling of our 110th operated Edmonton Sands well on December 23, 2005. The Company had finding, development and acquisition ("F,D&A") results of $18.83 per BOE on a proved plus probable basis. In 2005, Anderson Energy completed its largest and most successful drilling program in its history with the drilling of 118 gross (63.1 net) wells and a success rate of 92%. As of January 1, 2006, the Company has a five year drilling inventory of 910 locations.

For the year ended December 31, 2005, the Company averaged 2,256 BOED of production with fourth quarter production of 3,708 BOED. Production in 2005 was 137% higher than in 2004. Current production volumes at the time of writing this report are in excess of 4,500 BOED. In 2005, the Company's cash flow from operations was $25.5 million and earnings were $0.7 million. In 2004, the cash flow and loss were $6.2 million and $1.6 million, respectively. Field capital expenditures were $72.7 million in 2005 as compared to $41.4 million in 2004.

Net Asset Value. AJM Petroleum Consultants ("AJM") completed a NI 51-101 compliant reserve evaluation of all of the Company's petroleum and natural gas assets effective December 31, 2005. Anderson Energy has used AJM to conduct two prior annual evaluations of the Company's reserves. The Company's estimated fully diluted NAV per share for December 31, 2005 and 2004 is outlined below:

EVALUATION FORECAST PRICING

(thousands of dollars, except share data)	*December 31, 2005 AJM*	*December 31, 2004 AJM*
Pretax proved and probable reserves NPV 10%	$ 295,358	$ 69,625
Undeveloped land*	33,676	14,965
Debt, net of working capital	(24,597)	16,719
In the money option proceeds based on year end closing price	17,211	–
Total	$ 321,648	$ 101,309
Fully diluted number of shares *(thousands)*	51,742	33,565
Fully diluted NAV/share	$ 6.22	$ 3.02

* *based on a Seaton Jordan independent evaluation in 2005 and an internal estimate of $100/acre in 2004*

The net asset value has appreciated 106% in the past year.

Reserves and Finding, Development and Acquisition Costs. In the last 12 months, Anderson Energy increased its proved plus probable reserves base by 262% and has replaced its 2005 production with new proved plus probable (net of revisions) reserves additions by a factor of 17.1 times. The Company's net proved plus probable reserve additions in 2005 were a total of 14.1 MMBOE, of which 20% of the reserves additions came from the Aquest Energy corporate acquisition. The Company's reserve life indices for total proved reserves is 7.0 years and for total proved plus probable reserves is 13.4 years. This calculation was done using fourth quarter production. Reserves additions and revisions for 2005 are shown on the following table.

	Total Proved (MBOE)	*Total Proved Plus Probable (MBOE)*
Opening reserves at December 31, 2004	2,378	5,068
Acquisitions	1,865	2,793
Additions	5,081	11,718
Revisions	1,084	(419)
Production	(824)	(824)
Net change	7,206	13,268
Ending reserves at December 31, 2005	9,584	18,336

F,D&A costs including future development capital for the 12 months ended December 31, 2005 are $27.09 per BOE on a proved basis and $18.83 per BOE on a proved plus probable basis. The change in future development capital in the above costs are $8.46 per BOE total proved and $8.21 per BOE total proved plus probable. More details on F,D&A costs and F,D&A cautionary language are shown on pages 35 to 37 of this report.

On April 30, 2004, Anderson Energy entered into an agreement with CNGT where the Company committed to spend $15 million on CNGT lands over a two year period followed by a one year option to spend an additional $5 million to earn 50% of specific CNGT non-producing lands. In 10-1/2 months, on March 10, 2005, the Company completed the work commitment plus option and has earned 50% of CNGT's working interest in non-producing lands in the agreement. CNGT has since been acquired by Harvest Energy Trust. On December 23, 2005, the Company drilled its 110th Edmonton Sands well as a result of this transaction.

On June 28, 2005, Anderson Energy announced the acquisition of Aquest Energy pursuant to a plan of arrangement and subject to shareholder and regulatory approval. These approvals were obtained on September 1, 2005 and the Company commenced trading on the TSX on September 7, 2005 under the stock symbol AXL. Management and directors own over 20% of the issued and outstanding shares in the Company.

On June 28, 2005, Anderson Energy also announced a bought deal subscription receipts financing that closed on August 4, 2005 for net proceeds of $28.3 million.

As of March 13, 2006, Anderson Energy has estimated its behind pipe production to be 1,100 BOED, with 30% estimated to be on stream during spring breakup and the balance to be brought on stream later in the year. Included in the behind pipe estimate is 80 BOED of connected shut-in production awaiting AEUB holding application approvals.

Outlook. As of December 31, 2005, the Company has assembled a drilling inventory of 910 gross (317.7 net) locations on its lands. Approximately 56% of the net locations are Edmonton Sands prospective, 33% of the net locations are Horseshoe Canyon CBM development locations and the balance is distributed amongst the rest of the Company's projects. This represents a five year drilling inventory.

The Company continues to aggressively add to its Edmonton Sands drilling inventory through acquisition and farm-ins in the first quarter, which has materially increased its Edmonton Sands reserves since year end reserve bookings.

As of March 15, 2006, Anderson Energy has 35 gross (21 net) wells remaining to be tied-in for production in its year round access areas. The Company has added additional staff to accelerate well tie-ins.

Anderson Energy has reduced its capital budget for 2006 to $58 million (excluding acquisitions) and will be reviewing its budget on a quarterly basis.

The warm winter conditions in January have had a negative impact on the first quarter of 2006 and projected summer North American natural gas prices. The levels of natural gas storage heading into the summer injection season are at historic highs. The Company expects natural gas prices to be soft until next winter. While Anderson Energy continues to be bullish on the long-term prospects for natural gas, North American weather conditions, the geopolitics of crude oil pricing, and North American production declines will determine summer gas prices. However, at the end of the natural gas storage injection season, natural gas storage can be no more than full. When winter returns, natural gas prices should strengthen.

In the balance of the year, the Company will continue to develop its Edmonton Sands drilling opportunities, evaluate its CBM acreage and continue its north central and eastern Alberta drilling programs. Included in the CBM drilling evaluation are two high impact projects at Pearce (42% working interest in 36,312 acres) and Blood (100% working interest in 50,880 acres). As well, the Company will likely consolidate some of its interest on the Aquest Energy properties through further acquisitions and dispositions.

We would characterize 2005 as a year of achievement as we achieved liquidity for our private company shareholders by acquiring Aquest Energy through a court approved plan of arrangement. The Company has an impressive suite of growth opportunities highlighted by the Sylvan Lake Edmonton Sands play. We expect 2006 to be a year of execution as we continue to develop our 18 MMBOE of proved and probable reserves and initiate CBM drilling on our undeveloped acreage.

In this annual report, we describe the Edmonton Sands project, our CBM initiatives and our other exploration and development projects. The Company's Annual Information Form ("AIF") provides full NI 51-101 disclosure of reserves information and the Company's Annual Management Information Circular provides details of corporate governance initiatives. The Company's employees and consultants in the office and the field who define, plan, account for and execute our projects with their hard work and strong business ethics all work together towards a common goal of increasing shareholder value. We thank them for their efforts.

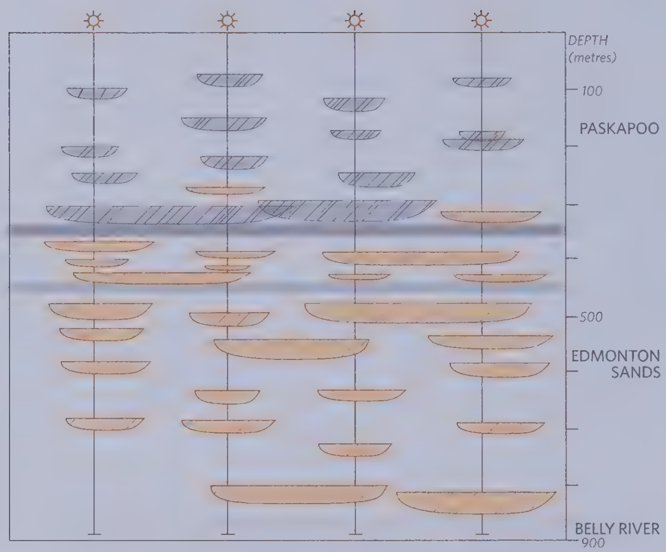
We look forward to 2006 and thank shareholders for their support.

Brian Dau
President & Chief Executive Officer
March 16, 2006

Edmonton Sands. An impressive growth opportunity.

The Company has an interest in 167 sections of land within the Edmonton Sands producing fairway in central Alberta. These lands were obtained through the CNGT farm-in transaction, Crown land sales, property acquisitions, freehold leasing, farm-in deals on third

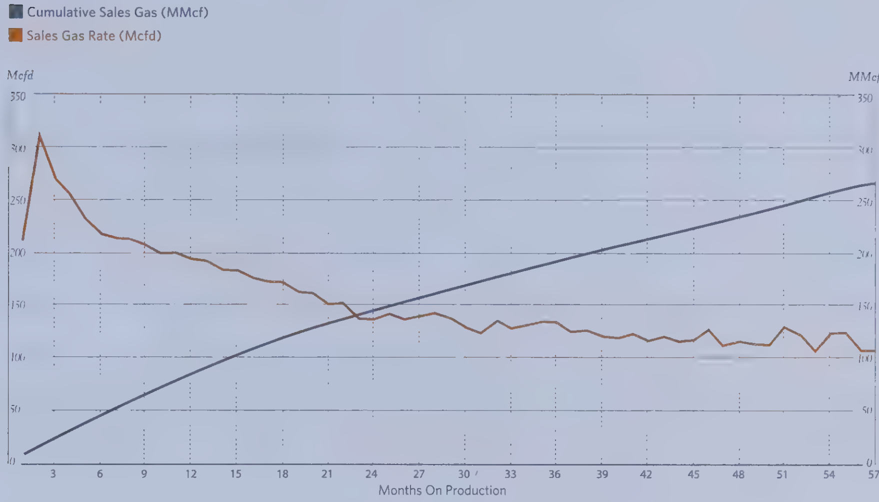
EDMONTON SANDS CROSS SECTION



The upper Cretaceous Edmonton group in central Alberta consists of two classic wedges sourced from the west prograding east in a primarily non-marine depositional setting. The lower Edmonton or Horseshoe Canyon contains abundant gas saturated channel sands. The upper Edmonton or Scollard formation is also non-marine channels and incised valley fills which can be laterally extensive. Edmonton wells are drilled to as deep as 1,150 metres with gas sands ranging in depth from 350 to 1,100 metres. The dry methane gas contained in the sands is locally sourced and contains no hydrogen sulphide. The Edmonton Sand outcrops in the river valleys to the east. It is not by definition a deep basin centered trap, but it shares many of the characteristics of a deep basin centered trap, including lower than normal reservoir pressures and no water production. The technical description of the Edmonton Sands is a continuous type deposit of hydrocarbons which is pervasive through a large area and is not significantly influenced by hydrodynamic influences. The Edmonton Sands reservoirs are all at irreducible water saturation with no moveable water.

There are up to 14 identified Edmonton Sands producing intervals on or near the Company interest land. Anderson Energy believes that to commercially develop as many of the potential 14 Edmonton producing sands in one section of land (one square mile), the Company needs to infill drill its lands to 160 acre spacing. Other operators have proved the concept of infill drilling to as dense as 80 acre spacing in the Edmonton Sands group. Where the productive commercial Edmonton Sands have been identified, AJM Petroleum Consultants ("AJM") has assigned 0.31 Bcf of original recoverable proved plus probable sales gas reserves per well on predominately 160 acre spacing in the greater Sylvan Lake area.

PRODUCTION HISTORY
AVERAGE EDMONTON SANDS WELL PERFORMANCE
TWP 35-01W5 to 39-05W5



Environmental considerations are integral to the Company's operations. During the initial planning stage, drilling locations and pipeline routings are selected with input from landowners and occupants to minimize surface impacts. To protect the shallow freshwater aquifers, the surface casing is set at 125 metres in depth and cemented to surface using a preset rig. A conventional rig is then moved on location to drill to the base of the Edmonton Sands group, which ranges in depth from 850 to 1,150 metres in this area. After logging, the production casing string is cemented full length to eliminate any possibility of contaminating the shallow fresh water aquifers. Cement bond logs are run to verify the integrity of the production casing cement job prior to completing the wells. Coiled tubing fracturing technology is utilized enabling up to 14 individual zones to be stimulated in one day.

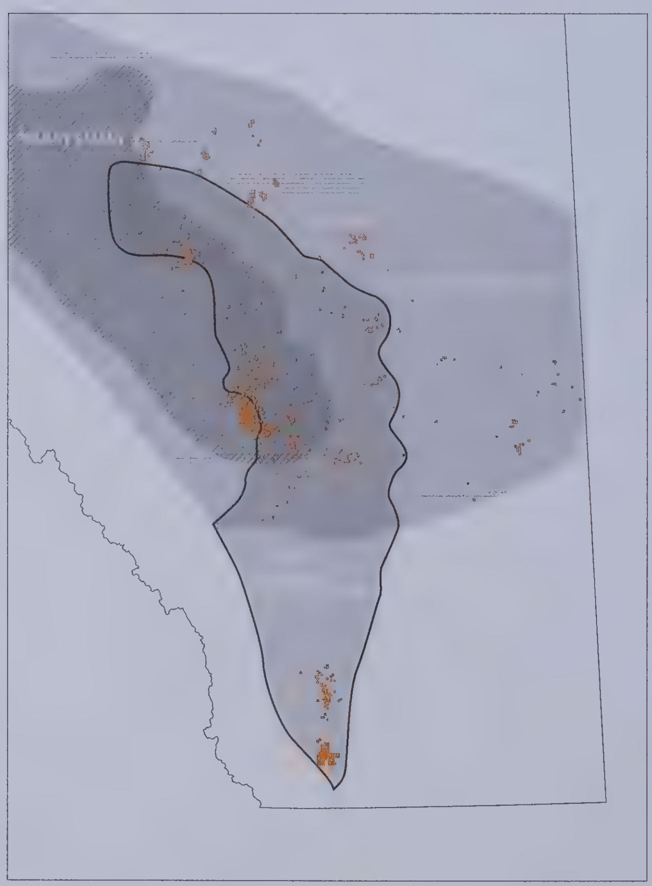
Production equipment consists of wet meter skids and 99 horsepower field compressors. In order to minimize noise impacts from compressors, they are situated at the well sites or at the tie-in point of the pipeline to existing infrastructure, thereby maximizing the distance from residences in the area. Additional sound attenuation equipment is added to the compressors as required to ensure sound levels are 35 decibels or less at the closest residence. This exceeds the AEUB criteria of 40 decibels at the closest residence. Typically, more than one well is tied-in to each field compressor. To minimize surface impact to the landowner or occupant, SCADA is installed on well sites that do not have compressors situated on them and these well sites and their accesses are restored as a "minimum impact site" thereby permitting the landowner or occupant to farm over the access road and up to the production equipment on the lease. The natural gas in the Edmonton formation has an average heat content of 970 Btu/scf.

Anderson Energy has 467 gross (177.6 net) locations to drill as of January 1, 2006, including those locations from additional Crown land sale acquisitions and farm-in deals done in the first quarter of 2006. The Company projects that it might take five years to drill up this inventory of locations. In 2006, the Company will be primarily focused on drilling undeveloped land with one to two wells per section. Subject to AEUB holding approval, the Company can proceed with four well per section drilling in 2007. On a 160 acre spacing development average, expected costs are $640,000 per well to drill, complete, equip and tie-in.

Coal bed methane (CBM) has emerged as a prolific and extensive resource play in central and southern Alberta. Known also as natural gas from coal (NGC), Horseshoe Canyon coal bed methane is very similar to shallow gas reservoirs such as the Edmonton and Belly River. Instead of residing within a sandstone, the natural gas is bonded to the coal matrix and produced using the same conventional methods as other shallow gas reservoirs. Horseshoe Canyon coals are a very attractive development target in Alberta as they are laterally extensive, found at suitable depths and, uniquely, they are a dry coal so water production is not an issue. This makes Horseshoe Canyon CBM an exciting and rapidly maturing new resource play in southern and central Alberta.

Coal Bed Methane Initiatives

COAL BED METHANE



Anderson Energy has various working interests within the known producing limits of the Horseshoe Canyon Coal Bed Methane producing fairway as shown in the map above.

The Company has allocated $4 million it the 2006 capital budget to conduct exploratory, development drilling and facility work. Anderson Energy has had various engineering consultants conduct CBM evaluation studies alongside Company personnel to assess the potential of the Company's acreage.

In 2006, the Company will be directing funds to three types of Horseshoe Canyon CBM projects. The first type of project is Tier 1 development locations. These locations are identified as having a minimum of six metres of clean coal net pay between a drill depth of 250 to 850 metres and offsetting commercial CBM development. Company geologists define the Tier 1 fairway as Township 24 to 44, Range 20 to 27 W4M. The Company had identified 246 gross (56 net) Tier 1 development locations on its lands using 160 acre spacing. The Company properties involved are Three Hills, Ghost Pine, Wimborne, Innisfail, Chigwell, Lone Pine and Mikwan. In the fourth quarter of 2005, six gross (1.2 net) wells were drilled on these lands primarily at Ghost Pine. The second type of project is Tier 2 development locations. The Company has identified 88 gross (48 net) Tier 2 development locations on its lands with potential to drill one to two wells per section in the Sylvan Lake, Edberg, Gilby and Leahurst areas. Company geologists have defined the Tier 2 fairway as a six to 12 mile band surrounding the Tier 1 fairway. Although the Tier 2 fairway meets the net pay cutoff, there is insufficient offsetting production history to justify four well per section development at this time. A portion of the Company's 2006 CBM capital program will target these areas along with drilling for Edmonton Sands and Belly River conventional gas reservoirs. The third type of Horseshoe Canyon CBM project is to drill two high impact wells in southern Alberta. If successful, they could substantially increase the Company's inventory of CBM development locations. The Company's two high impact CBM projects are described below:

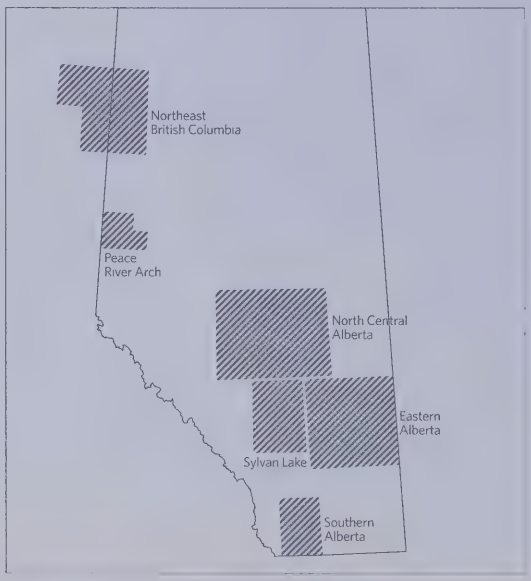
Pearce: Anderson Energy has an average working interest of 42% in 36,312 gross acres of land which, based on log control, could be prospective for Horseshoe Canyon CBM. In 2005, the Company drilled a deeper Cretaceous test which was subsequently completed in the Horseshoe Canyon coals. This completion proved the Horseshoe Canyon coals to be dry and permeable. The Company will be drilling a step out well to confirm gas content and assess commerciality of these lands in 2006.

Blood First Nations: The Company has a 100% working interest in 50,880 acres of land on and adjacent to Blood First Nations lands. The exploratory well being drilled will assess the permeability and gas content of the Horseshoe Canyon coals as well as determine if the Horseshoe Canyon coals require dewatering. Commerciality of CBM development on the Blood First Nations lands is likely dependent on the coals being dry.

The Company has various lands in north central and central Alberta where there has been considerable land sale activity for Mannville CBM. At present, the Company has no plans for Mannville CBM and is waiting on results from offsetting operators. Mannville CBM is not a dry coal and requires extensive dewatering with expensive horizontal well applications.

Property Review

Anderson Energy's operations are divided into six main regions of exploration and development activity based on geology and geography. The Company's focus in 2006 will be in the Sylvan Lake area, pursuing shallow Edmonton Sands drilling. Carbonate reef projects will be drilled in northeast British Columbia. Gas drilling will be undertaken on seismically identified projects in north central Alberta and the Peace River Arch. Medium to heavy oil drilling will take place in eastern Alberta and high impact CBM drilling will be undertaken in southern Alberta.



ANDERSON ENERGY PROPERTY

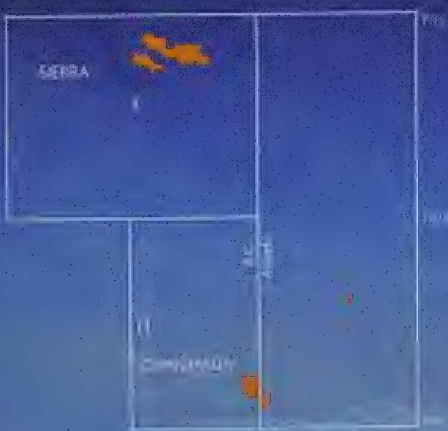
Northeast British Columbia

2005 Activity and Results:

- Undeveloped land: 84,346 gross (30,078 net) acres
- Drilling activity: six gross (1.2 net) wells
- Sales: 2.3 MMcfd of gas and four bpd of NGL
- Two properties: Chinchaga (operated) and Sierra (outside operated)

2006 Planned Activity:

- Chinchaga: one exploratory (100% working interest) and one development well (39% working interest) targeting Slave Point objectives
- Sierra: three Kakisa development wells and tie-in of three Jean Marie wells drilled in previous year (15% working interest)



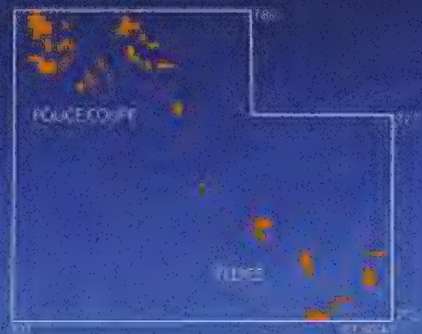
Peace River Arch

2005 Activity and Results:

- Undeveloped land: 47,678 gross (13,059 net) acres
- Drilling activity: eight gross (3.8 net) wells at 50% success rate
- Sales: 0.7 MMcfd of gas and 10 bpd of oil and NGL
- 14 square mile 3-D seismic acquisition

2006 Planned Activity:

- Teepee field compression project
- Drill two gross (0.5 net) wells planned targeting Cretaceous and Mississippian objectives



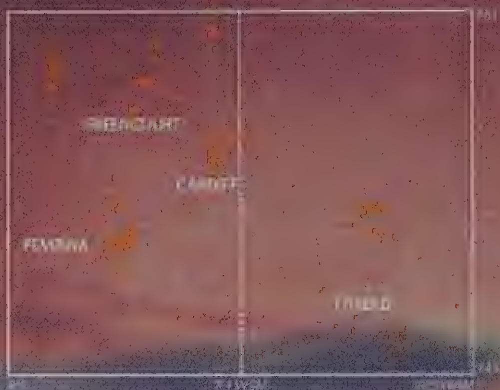
North Central Alberta

2005 Activity and Results:

- Undeveloped land: 91,569 gross (43,109 net) acres
- Drilling activity: six gross (4.3 net) wells, 83% success rate
- Sales: 2.8 MMcfd of gas and 96 bpd of oil
- Producing properties at Greencourt, Cardiff, Cooking Lake and Pembina

2006 Planned Activity:

- Drill five gross (1.9 net) wells, primarily targeting Cretaceous gas objectives
- Shoot two 3-D seismic programs totaling 16 square miles



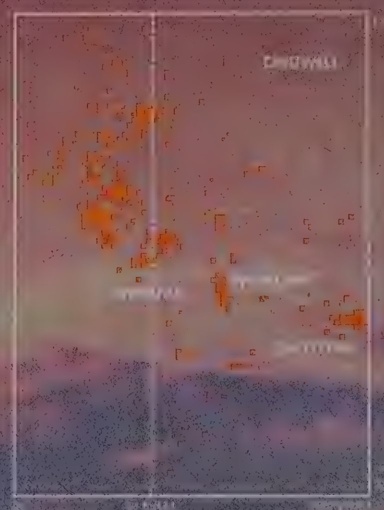
Sylvan Lake

2005 Activity and Results:

- Undeveloped land: 57,484 gross (31,262 net) acres
- Drilling activity: 86 gross (48.7 net) conventional wells at a 95% success rate and six gross (1.2 net) CBM wells
- Sales: 6.9 MMcfd of gas and 69 bpd of oil and NGL

2006 Planned Activity:

- Drill 55 gross ([illegible] net) wells. Majority of locations target Edmonton Sands with some planned CBM objectives and deeper Cretaceous objectives at Sylvan Lake
- Major facility projects in the Sylvan Lake area at Innisfail and Gilby



Eastern Alberta

2005 Activity and Results:

- Undeveloped land: 14,394 gross (7,189 net) acres
- Drilling activity: four gross (2.3 net) oil wells drilled
- Sales: 0.2 MMcfd of gas and 47 bpd of oil

2006 *Planned Activity:*

Drill eight gross (4.7 net) wells at [illegible] and [illegible], primarily targeting [illegible] oil targets.

Southern Alberta

2005 *Activity and Results:*

- Undeveloped land: [illegible] gross ([illegible] net) acres
- Drilling activity: one dry hole (CBM evaluation well)
- Sales: 0.2 MMcfd of gas and 1.4 bpd of oil and NGL

2006 *Planned Activity:*

- Drill two gross (1.4 net) CBM evaluation wells

DRILLING INVENTORY

The Company's drilling inventory as of January 1, 2006 is outlined below:

AREA	Gross Locations	Net Locations
Edmonton Sands locations identified in AJM Report	409	149.7
Edmonton Sands locations added since AJM Report	58	27.9
CBM development Tier 1	246	56.0
CBM development Tier 2	88	48.0
CBM exploratory projects	2	1.4
Sierra Northeast B.C. Kakisa	26	4.8
Sierra Northeast B.C. Jean Marie	34	6.0
Chinchaga	3	1.2
Eastern Alberta	15	10.3
Sylvan Lake Deep	11	3.9
North Central Alberta	9	5.6
Southern Alberta	5	2.0
Peace River Arch	4	0.9
Total	910	317.7

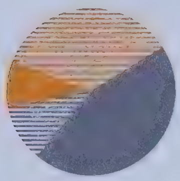
The Company expects it might take up to five years to drill its drilling inventory. Over 95% of the inventory would be considered to be development wells.

OPERATIONS OVERVIEW

Land. Seaton Jordan & Associates Ltd. prepared an evaluation of the Company's non-reserve oil and gas properties as of December 31, 2005 as summarized below:

Undeveloped Land	Gross Acres	Net Acres	Valuation (thousands)
Alberta	415,014	222,970	$ 30,036
British Columbia	77,131	23,824	3,640
Total	492,145	246,794	$ 33,676

In 2005, the Company acquired 5,702 gross (4,285 net) acres at an average cost of $248 per acre. This compares to 14,728 gross (8,307 net) acres in 2004 at an average cost of $159 per acre.



FOURTH QUARTER PRODUCTION (TOTAL 3,708 BOED)

(BOED)

- Sylvan Lake 1,670
- North Central Alberta 1,284
- Northeast B.C. 346
- Other 408

Drilling. In 2005, the Company completed its most successful drilling year:

WELLS DRILLED

	2005 Gross	2005 Net	2004 Gross	2004 Net
Gas	103	54.0	45	32.7
Oil	5	2.8	4	3.3
Dry	10	6.3	6	5.2
Total	118	63.1	55	41.2

The 2004 net to gross ratio of wells drilled was higher than in 2005 as 2004 was an earning year in the CNGT farm-in agreement and a significant number of wells were drilled at a high working interest as earning wells. In 2005, CNGT/Harvest was a 50% partner in many of the wells drilled. In 2005, the Company operated 96% of the net wells that were drilled as compared to 92% in 2004. Approximately 75% of the wells drilled in 2005 were drilled for Edmonton Sands at an average depth of 1,000 metres. The remaining wells drilled were in the Company's other focus areas with depths ranging from 1,000 to 2,500 metres. The high level of industry activity resulted in a shortage of drilling rigs and other related equipment and services. By committing to multi-well programs, the Company was able to secure equipment necessary to drill and complete its budgeted program. The balance of the wells were drilled with rigs obtained on windows from other operators. An extremely wet summer coupled with the high level of industry activity caused delays and negatively impacted costs. Still, the Company was able to achieve similar drilling and completion costs in the Edmonton Sands play in the fourth quarter of 2005 as compared to the fourth quarter of 2004 as the Company became more efficient and knowledgeable in the Edmonton Sands play.

Production. Sales volumes in the fourth quarter of 2005 averaged 3,708 BOED. This represents an increase of 220% over the fourth quarter of 2004.

SALES VOLUMES

	Q4 2005	2005	2004
Gas *(Mcfd)*	18,785	12,170	5,586
Oil *(bpd)*	409	154	2
NGL *(bpd)*	168	74	19
Total *(BOED)*	3,708	2,256	952

Sales volume growth has come from both the acquisition of Aquest Energy on September 1, 2005 and drilling in the Sylvan Lake area throughout the year. Sylvan Lake represented 45% of sales volumes in the fourth quarter of 2005.

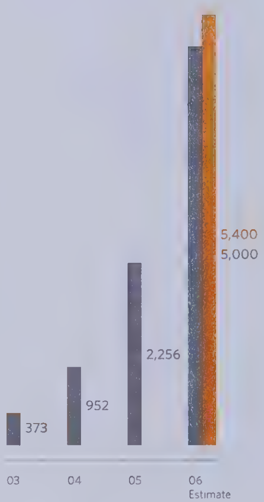
Quarterly sales by product is shown in the following table:

SALES VOLUMES

	Q1 2005	Q2 2005	Q3 2005	Q4 2005
Gas *(Mcfd)*	8,165	9,623	11,991	18,785
Oil *(bpd)*	6	15	181	409
NGL *(bpd)*	22	35	69	168
Total *(BOED)*	1,389	1,653	2,249	3,708

Current production at time of writing of this report is approximately 4,500 BOED with approximately 1,100 BOED of behind pipe capacity. The Company expects to tie-in approximately 30% of the production during the second quarter and the balance in the third and fourth quarters subject to regulatory and landholder approvals.

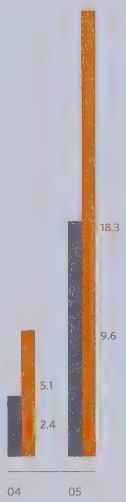
Reserves and F,D&A Costs. The Company's reserves were evaluated by AJM Petroleum Consultants in accordance with NI 51-101 as of December 31, 2005 and are included in the MD&A section of this annual report.



PRODUCTION HISTORY

(BOED)

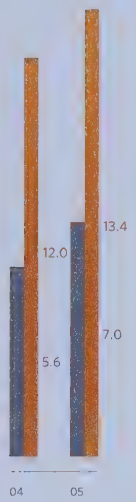
Production
2006 Upside



RESERVES GROWTH

(MMBOE)

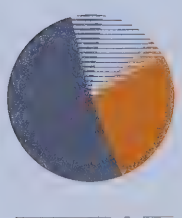
Proved
Proved + Probable



RESERVES LIFE INDICES

(years)

Proved
Proved + Probable



PROVED PLUS PROBABLE RESERVES DISTRIBUTION BY PROPERTY (TOTAL 18.34 MMBOE)

(MMBOE)

Greater Sylvan Lake Edmonton Sands 9.65
Sierra Ekwan 1.88
Chinchaga 1.07
Greencourt 0.75
Other 4.99

RESERVES SUMMARY

AJM Petroleum Consultants were engaged to evaluate the reserves of the Company effective December 31, 2005. As at this date, using AJM forecast pricing, Company reserves are summarized in the table below.

SUMMARY OF OIL AND GAS RESERVES AS OF DECEMBER 31, 2005

Reserves Category	*Light and Medium Oil (Mbbls)*	*Sales Gas (MMcf)*	*Natural Gas Liquids (Mbbls)*
Proved developed producing	340	19,856	194
Proved developed non-producing	35	2,542	47
Proved undeveloped	234	29,509	84
Total proved	609	51,907	325
Probable	271	49,211	278
Total proved plus probable	880	101,118	603

Reserve additions for the year, including net acquisitions and net revisions, amounted to 8.0 MMBOE total proved and 14.1 MMBOE total proved plus probable. The only material acquisition during 2005 was the Aquest Energy deal. Aquest Energy additions were 1.9 MMBOE total proved and 2.8 MMBOE total proved plus probable. The majority of reserves drilling additions in 2005 occurred in the Edmonton Sands in the greater Sylvan Lake area. Total proved reserves additions here were 3.2 MMBOE and proved plus probable additions in the Edmonton Sands were 6.9 MMBOE. Company total proved revisions for 2005 were plus 1.1 MMBOE while total proved plus probable revisions were minus 0.4 MMBOE. Total proved reserves were bolstered by the continued strong performance of wells at Sylvan Lake, Chinchaga, Greencourt East and Goodridge-Westlock.

Health, Safety and Environment. Responsibility for protecting the environment, as well as the health and safety of our employees, contractors and the public is a commitment made by everyone at Anderson Energy – from senior management to our field employees.

Environment. Anderson Energy is committed to minimizing the impact of its activities on the environment while developing its energy resources economically and efficiently. The Company has established an Environmental Policy that integrates the following guiding principles:

– *Comply with applicable environmental law, industry standards and internal policies;*
– *Make environmental considerations an integral part of planning processes;*
– *Operate facilities and handle raw materials in a manner that protects the environment and the safety and the health of employees and the public;*
– *Promptly provide relevant information to all stakeholders affected by our operations and be responsive and sensitive to legitimate stakeholder concerns;*
– *Identify and mitigate the adverse impacts of operations on the environment in keeping with good environmental and business practices;*
– *Respond to emergencies in a prompt and efficient manner; and*
– *Commit sufficient resources to ensure that our employees are fully informed of their responsibilities and are trained to protect the environment while performing their duties.*

Health and Safety. Anderson Energy is committed to conducting operations in a safe manner protecting the health and safety of employees, contractors and community residents. The Company has implemented a Safety Program modeled after the Enform (formerly the Petroleum Industry Training Service) Basic Safety Program and has initiated the necessary steps towards obtaining an Alberta Partnership Program Certificate of Recognition.

Anderson Energy is committed to continuous improvements in health and safety practices and conducts routine safety audits at our worksites to ensure regulatory requirements are exceeded or met.

Corporate Citizenship. Establishing and maintaining good community relations is a high priority of the Company. As part of our strategy for improving landowner communications, an open house was held in the fall to present our development plans to the residents in the Markerville area. The response to the open house was positive and our development projects are proceeding with the support of the public.

For the Years Ended December 31, 2005 and 2004

The following discussion and analysis of financial results should be read in conjunction with the audited consolidated financial statements of Anderson Energy Ltd. ("Anderson Energy" or "the Company") for the year ended December 31, 2005 and 2004 and is based on information available as of March 16, 2006.

Production and reserve numbers are stated before deducting crown or lessor royalties. Included in the discussion and analysis are references to terms commonly used in the oil and gas industry such as cash flow from operations and barrel of oil equivalent. Cash flow from operations as used in this report represents cash provided by operations before changes in non-cash working capital and asset retirement expenditures. Anderson Energy believes that cash flow from operations represent both an indicator of the Company's performance and a funding source for on-going operations.

Production volumes and reserves are commonly expressed on a barrel of oil equivalent (BOE) basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants. These terms are not defined by Canadian GAAP and therefore are referred to as non-GAAP measures. A BOE conversion ratio of six thousand cubic feet to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

The information contained herein contains forward looking statements and assumptions, such as those relating to results of operations and financial condition, capital spending, financial resources, commodity prices and costs of production. By their nature, forward looking statements are subject to numerous risks and uncertainties that could significantly affect anticipated results in the future and, accordingly, actual results may differ materially from those predicted. The forward looking statements contained herein are as of March 16, 2006 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward looking statements.

All references to dollar values are to Canadian dollars unless otherwise stated.

The abbreviations used in this discussion and analysis are located on page 56 of this annual report.

ACQUISITION OF AQUEST ENERGY LTD.

On June 27, 2005, the Company entered into an Arrangement Agreement with Aquest Energy Ltd. ("Aquest Energy"), a publicly traded oil and gas company. Pursuant to the Arrangement, Anderson Energy acquired all of the outstanding shares of Aquest Energy for consideration of 0.31 Anderson Energy shares for each Aquest Energy share, for total consideration of 9.6 million Anderson Energy common shares or $53.1 million before transaction costs. Transaction costs were $1.0 million and net debt assumed was $26.5 million for a total acquisition cost of $80.6 million. The acquisition was approved by the shareholders of both Anderson Energy and Aquest Energy and received regulatory approval on August 31, 2005 and the transaction closed on September 1, 2005. The acquisition has been accounted for using the purchase method of accounting. Aquest Energy was producing approximately 1,800 BOED (64% natural gas), had 2,812.5 MBOE of proved plus probable reserves and 58,000 net acres of undeveloped land at the time of the acquisition and had a broad portfolio of opportunities specifically complementing Anderson Energy's Sylvan Lake core area.

On June 27, 2005, the Company also agreed to issue and sell, on a private placement "bought deal" basis to a syndicate of Canadian underwriters, subscription receipts and flow-through common shares. On August 4, 2005, a total of 3,100,000 subscription receipts priced at $6.50 each and 1,250,000 flow-through common shares priced at $8.00 each were sold for aggregate gross proceeds of $30,150,000. The proceeds from the sale of the subscription receipts and flow-through common shares were held in escrow pending completion of the Aquest Energy transaction and after release from escrow, were used to repay indebtedness of the combined companies and fund exploration, development and acquisition activities. Net proceeds after commissions and expenses were $28.3 million.

Effective September 1, 2005, the Company became a reporting issuer. The Company commenced trading on the Toronto Stock Exchange on September 7, 2005.

REVIEW OF FINANCIAL RESULTS

Revenue and Production. Gas sales made up 90% of Anderson Energy's total oil and gas sales for the year ended December 31, 2005 compared to 98% of total oil and gas sales for the year ended December 31, 2004.

Gas sales volumes for year ended December 31, 2005 increased 118% to 12.2 MMcfd from 5.6 MMcfd last year. The increase relates to the acquisition of Aquest Energy and new wells on production as a result of drilling during the year. As a result of both of these factors, Sylvan Lake has become the Company's largest area of production, with gas sales of 6.0 MMcfd, followed by north central Alberta with gas sales of 2.8 MMcfd and northeast British Columbia with gas sales of 2.3 MMcfd.

The fourth quarter of 2005 represents the first full quarter of revenue and production since the Aquest Energy transaction, which closed on September 1, 2005. The Company achieved average gas sales of 18.8 MMcfd in the fourth quarter. This compares to 12.0 MMcfd in the third quarter of 2005 and 6.8 MMcfd in the fourth quarter of 2004. Fourth quarter gas sales were less than expected due to plant turnarounds and high line pressures which curtailed and later restricted production at Teepee, dew point control problems at the outside operated Ladyfern plant which curtailed Chinchaga production for the last two weeks of the year and some Sylvan Lake Edmonton Sands wells shut-in awaiting AEUB approval of holding applications. The problems at Teepee have mostly been rectified with the installation of field compression which brought Teepee on near capacity on March 3, 2006. The Chinchaga field was fully restored to production on January 11, 2006. On February 9, 2006, the Sylvan Lake Tindastoll compression project was completed. This project was designed to alleviate some of the gas gathering bottlenecks in this area and to provide more room for wells currently shut-in awaiting AEUB approval of holding applications. The pertinent AEUB applications were approved on March 8, 2006.

Oil sales for year ended December 31, 2005 were 154 bpd compared to two bpd for the year ended December 31, 2004. Oil production averaged 409 bpd in the fourth quarter of 2005 compared to 181 bpd in the third quarter of 2005. The increase in production is almost entirely related to the Aquest Energy acquisition. The majority of the oil production is from central and eastern Alberta.

Natural gas liquids sales for year ended December 31, 2005 were 74 bpd compared to 19 bpd for the year ended December 31, 2004. Natural gas liquids sales averaged 168 bpd in the fourth quarter of 2005 compared to 69 bpd in the third quarter of 2005 and 17 bpd in the fourth quarter of 2004. The increase is primarily due to the Aquest Energy acquisition and new production in British Columbia and north central Alberta. Edmonton Sands production at Sylvan Lake is dry and produces minimal amounts of natural gas liquids.

The following tables outline production revenue, volumes and average sales prices for the year and for the fourth quarter.

OIL AND NATURAL GAS REVENUE

	Three months ended December 31		*Year ended December 31*	
(thousands of dollars)	2005	2004	2005	2004
Natural gas	$ 19,690	$ 4,046	$ 41,847	$ 13,400
Oil	1,934	41	3,075	42
NGL	911	78	1,583	319
Royalty and other	359	5	448	5
Total	$ 22,894	$ 4,170	$ 46,953	$ 13,766

PRODUCTION

	Three months ended December 31 2005	2004	Year ended December 31 2005	2004
Natural gas *(Mcfd)*	18,785	6,799	12,170	5,586
Oil *(bpd)*	409	8	154	2
NGL *(bpd)*	168	17	74	19
Total *(BOED)*	3,708	1,159	2,256	952

PRICES

	Three months ended December 31 2005	2004	Year ended December 31 2005	2004
Natural gas *($/Mcf)*	$ 11.39	$ 6.47	$ 9.42	$ 6.55
Oil *($/bbls)*	51.34	55.45	54.72	55.45
NGL *($/bbls)*	58.97	49.18	58.41	46.40
Total *($/BOE)*	$ 66.05	$ 39.08	$ 56.46	$ 39.50

Anderson Energy's average gas sales price was $9.42 per Mcf for the year ended December 31, 2005 compared to $6.55 per Mcf for the year ended December 31, 2004. For the three months ended December 31, 2005, the gas sales price was $11.39 per Mcf. This compares to $9.68 per Mcf realized in the third quarter of 2005 and $ 6.47 per Mcf realized in the fourth quarter of 2004. Gas prices increased significantly over the course of the year but have fallen off in the first quarter of 2006. The Company expects prices to remain at these lower levels through the summer of 2006.

The physical fixed price contracts assumed in the Aquest Energy acquisition all expired at the end of 2005 and are shown below:

	Volume/day	Price
Natural Gas		
September to October 2005	1,000 GJ/day	$7.15/GJ
Crude Oil		
September to December 2005	100 bpd	$45.40 to $51.40 US/bbl
September to December 2005	100 bpd	$46.80 US/bbl

Anderson Energy sells most of its gas at Alberta spot market prices and has not entered into any fixed price or forward contracts for the sale of its production, other than as noted above. In 2005 and 2004, Anderson Energy has classified all transportation costs as an offset to gas sales revenue as title transfers prior to transport on the applicable sales pipelines and transportation is being held by and charged by the gas purchasers. In December 2005, the Company has arranged firm service transportation agreements covering seven MMcfd of gas sales in the Sylvan Lake area for a three year term.

Royalties. Royalties were 22% of revenue for the year ended December 31, 2005 compared to 22% of revenue for the year ended December 31, 2004. Royalties were 24% of the revenue in the fourth quarter of 2005 compared to 20% of revenue in the third quarter and 14% of revenue in the fourth quarter of 2004. The unusually low royalty rate in the fourth quarter of 2004 was due to one-time royalty credits on two horizontal wells drilled at Chinchaga in 2004. These wells now attract full royalty charges. The 2005 royalty rate before this adjustment was lower than the previous year as a result of the ARTC associated with the new wells drilled in Alberta and 2004 gas cost allowance and custom processing credits recorded in 2005. The Company reached the maximum ARTC entitlement of $500,000 per year in 2005. In 2005, 68% of total royalties were payable to the Crown. This percentage is expected to decrease in 2006 as a significant number of properties acquired on the Aquest Energy acquisition were on freehold lands and a significant portion of the new drilling at Sylvan Lake is on freehold lands. On an absolute dollar basis, total royalties are expected to increase in 2006 as revenue increases. Royalty rates are also expected to increase as the fixed ARTC credit will have less of an impact on the gross amount of royalties paid and more drilling on farm-in lands may result in higher overriding royalty obligations.

	Three months ended December 31		*Year ended December 31*	
	2005	2004	2005	2004
Royalties (%)	24%	14%	22%	22%
Royalties ($/BOE)	$ 15.83	$ 5.55	$ 12.35	$ 8.65

Operating Expenses. Operating expenses were $9.08 per BOE for the year ended December 31, 2005 compared to $7.85 per BOE for the year ended December 31, 2004. Operating expenses were $8.47 in the fourth quarter of 2005 compared to $9.76 in the third quarter and $7.43 in the fourth quarter of 2004. Operating expenses in the fourth quarter reflect the first full quarter with Aquest Energy properties. The Company expects operating costs to increase as more production will be coming from Sylvan Lake. Sylvan Lake production is transported and processed through more expensive third party owned infrastructure and facilities.

OPERATING NETBACK

	Three months ended December 31		*Year ended December 31*	
(thousands of dollars)	2005	2004	2005	2004
Revenue	$ 22,894	$ 4,170	$ 46,953	$ 13,766
Royalties	(5,399)	(592)	(10,173)	(3,012)
Operating expenses	(2,890)	(791)	(7,480)	(2,736)
	$ 14,605	$ 2,787	$ 29,300	$ 8,018
Sales (MBOE)	341.2	106.6	823.6	348.4
Per BOE				
Revenue	$ 67.11	$ 39.13	$ 57.01	$ 39.51
Royalties	(15.83)	(5.55)	(12.35)	(8.65)
Operating expenses	(8.47)	(7.43)	(9.08)	(7.85)
	$ 42.81	$ 26.15	$ 35.58	$ 23.01

General and Administrative Expenses. General and administrative expenses were $4.54 per BOE for the year ended December 31, 2005 compared to $6.40 per BOE for the year ended December 31, 2004. General and administrative expenses were $3.51 per BOE in the fourth quarter of 2005 compared to $4.39 per BOE in the third quarter and $6.29 per BOE in the fourth quarter of 2004. On an absolute basis, general and administrative expenses were higher in the fourth quarter as a result of the Aquest Energy acquisition which resulted in increased staff and one time integration costs, including rent at more than one facility until February 2006, computer system conversion costs and moving costs. Integration costs were $340,000 in the fourth quarter and are expected to be $185,000 in the first quarter of 2006. It is expected that overall general and administrative expenses will increase as a result of increased staffing levels to manage the growth in drilling activity, significantly higher lease rental rates and the additional costs associated with being a public company. General and administrative expenses consist largely of salaries, rent, computer and other office costs. As the Company increases its production in 2006, general and administrative costs on a per BOE basis are expected to decline.

The Company follows the CICA accounting standard requiring the fair value method of accounting for stock-based compensation plans. The adoption of the new standard will have a greater impact on the Company now that it is public. Stock-based compensation expense was $102,963 in 2005.

	Three months ended December 31		Year ended December 31	
(thousands of dollars)	2005	2004	2005	2004
General and administrative (gross)	$ 2,430	$ 982	$ 6,426	$ 3,118
Overhead recovery	(461)	(123)	(969)	(192)
Capitalized	(771)	(189)	(1,715)	(694)
General and administrative (net)	$ 1,198	$ 670	$ 3,742	$ 2,232
General and administrative *($/BOE)*	$ 3.51	$ 6.29	$ 4.54	$ 6.40
% Capitalized	32%	19%	27%	22%

In light of going public, the Company has reevaluated some of its assumptions regarding capitalized general and administrative costs in order to be more in line with its peer group and to consider its anticipated capital program and additional staff. This has resulted in an increase in the percentage capitalized in the last half of 2005. Capitalized general and administrative costs are limited to salaries and associated office rent of staff involved in capital activities.

Interest Expense. In connection with the Aquest Energy acquisition, the Company increased its bank line to $45 million. The fees associated with this debt facility are included in interest expense. The effective interest rate on outstanding debt was approximately 5% in 2005. Interest expense is expected to increase in 2006. The Company expects its debt balance to peak with its winter drilling program at approximately $40 million net of working capital in the first quarter and then to fall by the fourth quarter as cash flow catches up with spending.

Depletion and Depreciation. Depletion and depreciation was $28.19 per BOE for the year ended December 31, 2005 compared to $24.07 per BOE in 2004. Depletion and depreciation was $28.60 per BOE in the fourth quarter of 2005 compared to $27.63 per BOE in the third quarter and $32.00 per BOE in the fourth quarter of 2004. Depletion and depreciation expense is calculated based on proved reserves only and is significantly impacted by the fact that only 39% of the Company's total reserves as of March 31, 2005 were proved. This number increased to 52% at December 31, 2005 which affected fourth quarter rates only. The proved ratio reflects the newness of the wells that make up the reserve evaluation. Fourth quarter expense was also affected by the increase in future development costs to $73.5 million associated with the Sylvan Lake reserve additions and the large increase in production volumes. The Company expects the depletion and depreciation rate to remain at similar rates in 2006.

Goodwill. In connection with the Aquest Energy transaction, the Company recorded $14.3 million of goodwill. The goodwill largely reflects the difference between the book base and the tax base of the assets and the associated recording of future income tax liabilities. The allocation to goodwill increased by $1.5 million from the Company's initial estimate provided in the third quarter as a result of a detailed review of asset retirement obligations associated with the acquired properties and as a result of additional operating expenses related to the pre acquisition period.

Asset Retirement Obligation. As a result of new drilling, the Company incurred $1.1 million in asset retirement obligations in the fourth quarter of 2005 and $3.3 million for the year ended December 31, 2005. Accretion expense was $0.4 million for 2005 and was included in depletion and depreciation expense.

Income Taxes. Anderson Energy is not currently taxable except for large corporations tax. The Company does not anticipate paying current income tax in 2006. The estimated tax pool balances at December 31, 2005 are summarized below. Tax pool classifications are estimates as some new wells have not yet had their status as exploratory or development confirmed.

The subscription receipts financing completed on September 1, 2005 included $10 million of flow-through shares. The flow-through share renouncement will be made on February 28, 2006 for qualifying exploration expenditures that will be incurred between September 1, 2005 and December 31, 2006. The tax pool estimate below has been reduced for this expected renouncement. The tax pool estimate has also been reduced for the effect of income recorded in 2005 that will not be taxed until 2006.

CEE	$ 43 million
CDE	$ 36 million
UCC	$ 39 million
COGPE	$ 28 million
Other	$ 7 million
Total	$153 million

Cash Flow from Operations. Cash flow from operations increased 310% to $25.5 million or $0.66 per share in 2005 from $6.2 million or $0.21 per share in 2004. For the three months ended December 31, 2005, cash flow from operations was $13.2 million or $0.28 per share, an increase of 96% over the previous quarter of $6.7 million or $0.18 per share, and 519% over the fourth quarter of 2004 of $2.1 million or $0.07 per share.

Earnings. The Company reported earnings of $1.8 million in the fourth quarter and $0.7 million for the year ended December 31, 2005 versus losses of $0.8 million for the fourth quarter and $1.6 million for the year ended December 31, 2004. The Company does not expect to be able to report significant earnings until it gets proved reserve recognition for its probable undeveloped reserves.

CAPITAL EXPENDITURES

The Company spent $25.6 million in capital additions in the fourth quarter and $72.7 million for the year ended December 31, 2005, not including the acquisition of Aquest Energy. The acquisition cost of Aquest Energy was $80.6 million including assumed debt and working capital. The breakdown of expenditures, net of the Aquest Energy acquisition, is shown below:

(thousands of dollars)	*Three months ended December 31* 2005	*Year ended December 31* 2005	2004
Land, geological and geophysical costs	$ 2,505	$ 4,920	$ 4,086
Property acquisitions, net of dispositions	(108)	(88)	(560)
Drilling, completion and recompletion	17,442	43,982	29,499
Facilities and well equipment	4,418	20,216	7,421
Office equipment and furniture	275	362	45
Asset retirement costs	1,103	3,338	876
Total	$ 25,635	$ 72,730	$ 41,367

On April 30, 2004, Anderson Energy entered into a strategic alliance agreement with an oil and gas royalty trust. The Company undertook an initial work commitment of $15 million to be spent over two years with an option to spend an additional $5 million over an additional year. The work commitment was spent on rig related earning operations. The Company earned a 50% interest in each operation it conducted. Upon spending the full commitment amount, it earned a 25% interest in various additional undeveloped lands. Upon exercising an option to spend an additional $5 million, it earned a total of 50% in the undeveloped lands. The Company fulfilled both its initial work commitment and option commitment in the first quarter of 2005.

Drilling statistics are shown below:

	Three months ended December 31				*Year ended December 31*			
	2005		*2004*		*2005*		*2004*	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Gas	40.0	19.1	22.0	17.7	103.0	54.0	45.0	32.7
Oil	4.0	2.4	3.0	3.0	5.0	2.8	4.0	3.3
Dry	5.0	2.5	3.0	2.2	10.0	6.3	6.0	5.2
Total	49.0	24.0	28.0	22.9	118.0	63.1	55.0	41.2
Success rate *(%)*	90%	90%	89%	90%	92%	90%	89%	87%

For the fourth quarter of 2005, 67% of the gross wells drilled were in Sylvan Lake and for the year ended December 31, 2005, 71% of the gross wells drilled were in Sylvan Lake. Remaining wells were drilled in Greencourt, Peace River Arch, Pouce Coupe and Provost.

The Company reported improved finding and development costs in 2005. After revisions, finding, development and acquisition costs, including future development capital, were $27.09 per BOE on a proved basis and $18.83 per BOE on a proved plus probable basis. This compares to $54.58 per BOE on a proved basis and $20.76 per BOE on a proved plus probable basis in 2004. The improvements reflect the success of the Edmonton drilling program and achieving probable recognition for the Company's Edmonton Sands drilling inventory.

Subsequent to year end, the Company issued 576,394 common shares at an average price of $7.74 per share as consideration for the purchase of oil and gas properties in various areas of central and eastern Alberta. The aggregate purchase price of the assets acquired in the five separate transactions was $4.5 million. Two of the transactions were with companies controlled by a director of Anderson Energy for total consideration of 224,660 shares at an average price $7.81 per share or $1.8 million. The two related party transactions were completed under the same terms and conditions as the other transactions. The independent directors of the board and the TSX approved the transaction. The assets acquired were silent partner working interests controlled by individuals previously associated with a subsidiary of Aquest Energy, Eravista Explorations Ltd. The acquisitions increase and simplify the Company's working interests in a number of assets acquired as part of the Aquest Energy corporate acquisition.

SHARE INFORMATION

The Company's shares have been listed on the Toronto Stock Exchange since September 7, 2005 under the symbol "AXL". As of December 31, 2005, there were 48.0 million common shares outstanding and 4.2 million stock options outstanding. During 2005, 9.6 million shares were issued on the acquisition of Aquest Energy, 4.4 million shares were issued with respect to a financing and 0.4 million shares were issued under the employee stock option plan. The Company's market capitalization at December 31, 2005 was $371 million. The annualized trading turnover ratio was 78%. As of March 16, 2006, there were 48.6 million shares outstanding and 4.4 million stock options outstanding.

SHARE PRICE ON TSX

	Q3 2005	Q4 2005
High	$ 10.00	$ 8.38
Low	$ 7.40	$ 7.00
Close	$ 8.05	$ 7.75
Volume	4,325,372	7,696,626
Shares outstanding		47,967,708
Market capitalization at December 31, 2005		$ 371,749,737

The Company's cash flow from operations and earnings are highly sensitive to changes in factors that are beyond its control. An estimate of the Company's sensitivities to changes in commodity prices, exchange rates and interest rates is summarized below:

	Cash Flow from Operations		Earnings	
	Millions	Per Share	Millions	Per Share
$0.10/Mcf in price of natural gas	$ 0.8	$ 0.02	$ 0.5	$ 0.01
US $1.00/bbl in the WTI crude price	$ 0.3	$ 0.01	$ 0.2	–
US $0.01 in the U.S./Cdn exchange rate	$ 0.6	$ 0.01	$ 0.4	$ 0.01
1% in short-term interest rate	$ 0.4	$ 0.01	$ 0.3	$ 0.01

RESERVES AND F,D&A COSTS

The Company's reserves were evaluated by AJM Petroleum Consultants in accordance with NI 51-101 as of December 31, 2005. The tables in this section are an excerpt from what will be filed in the Company's Annual Information Form ("AIF"). The AIF including the Company's NI 51-101 Forms F1, F2 and F3 filings on SEDAR constitute the Company's NI 51-101 annual required filings.

SUMMARY OF OIL AND GAS RESERVES

	Natural Gas		Light & Medium Oil		Natural Gas Liquids		Total BOE	
	Gross (Bcf)	Net (Bcf)	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MBOE)	Net (MBOE)
Proved Developed Producing	19.9	16.0	339.7	293.8	194.2	138.5	3,843	3,108
Proved Developed Non-Producing	2.5	2.1	35.1	33.1	46.6	35.9	505	412
Proved Undeveloped	29.5	24.3	233.9	208.2	83.9	62.9	5,236	4,323
Total Proved	51.9	42.4	608.7	535.1	324.7	237.3	9,584	7,843
Probable	49.2	39.5	271.5	237.5	278.6	203.1	8,752	7,016
Total Proved Plus Probable	101.1	81.9	880.2	772.6	603.3	440.4	18,336	14,859

Note: Coal Bed Methane and Heavy Oil Reserves are insignificant and are included in the Natural Gas and Light & Medium Oil categories.

NET PRESENT VALUE BEFORE INCOME TAXES

(AJM DECEMBER 31, 2005 PRICE FORECAST, ESCALATED PRICES)

(Thousands of dollars)	0%	5%	10%	15%
Proved Developed Producing	132,677	117,887	106,734	98,215
Proved Developed Non-Producing	17,358	13,847	11,621	10,091
Proved Undeveloped	88,166	72,633	60,689	51,294
Total Proved	238,201	204,367	179,044	159,600
Probable	217,110	154,569	116,314	90,864
Total Proved Plus Probable	455,311	358,936	295,358	250,464

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

AS OF DECEMBER 31, 2005

FORECAST PRICES AND COSTS

		Oil		Natural Gas	Edmonton Liquids Prices				
Year	WTI Cushing ($US/bbl)	Edmonton City Gate ($Cdn/bbl)	Hardisty Heavy ($Cdn/bbl)	AECO Gas Price ($Cdn/Mcf)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	Inflation Rate %	Exchange ($US/$Cdn)
2006	60.00	69.60	44.60	11.50	45.20	55.70	73.10	0.0	0.85
2007	61.20	71.00	46.00	10.50	46.15	56.80	74.55	2.0	0.85
2008	62.45	72.50	47.50	8.90	47.15	58.00	76.15	2.0	0.85
2009	61.60	71.50	46.50	8.50	46.50	57.20	75.10	2.0	0.85
2010	59.55	69.10	44.10	8.70	44.90	55.30	72.55	2.0	0.85
2011	55.15	63.90	38.90	8.90	41.55	51.10	67.10	2.0	0.85
2012	56.35	65.30	40.30	9.10	42.45	52.25	68.55	2.0	0.85
Thereafter 2%									

The future development capital included in the reserve evaluation is $73.5 million for total proved reserves and $135 million for total proved plus probable reserves.

The gross reserves continuity for 2005 is shown below:

	Natural Gas (Bcf)			Oil & Natural Gas Liquids (Mbbls)		
	Proved	Probable	Total	Proved	Probable	Total
Opening Balance December 31, 2004	13.7	15.0	28.7	99.0	181.0	280.0
Acquisitions net of dispositions	8.1	4.4	12.5	516.0	188.0	704.0
Drilling activity	28.0	37.5	65.5	412.3	387.7	800.0
Revisions	6.6	(7.7)	(1.1)	(10.6)	(206.7)	(217.3)
Production	(4.5)	–	(4.5)	(83.3)	–	(83.3)
Closing Balance December 31, 2005	51.9	49.2	101.1	933.4	550.0	1,483.4

FINDING, DEVELOPMENT & ACQUISITION COSTS

	Exploration, Development and Acquisition Costs (thousands)	*Change in Future Development Costs (thousands)*	*Total Costs (thousands)*	*Net Additions* (MBOE)*	*Finding, Development and Acquisition Costs ($/BOE)*
2005 Proved	$ 149,619	$ 67,933	$ 217,552	8,030	$ 27.09
2005 Proved Plus Probable	149,619	115,730	265,349	14,092	18.83
2004 Proved	40,446	764	41,210	755	54.58
2004 Proved Plus Probable	40,446	10,341	50,787	2,446	20.76
3 Year Average Proved	230,134	73,524	303,658	10,718	28.33
3 Year Average Proved Plus Probable	230,134	134,988	365,122	19,288	18.93

** Net Additions are defined as gross reserve additions minus gross reserve revisions.*

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. A BOE conversion ratio of 6 Mcf:1 bbls is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Since inception, the Company's F,D&A costs in aggregate have been $29.25 per BOE total proved and $19.35 per BOE total proved and probable.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2005, Anderson Energy had outstanding bank loans of $11.4 million and a working capital deficiency of $13.2 million. The Company expects to spend $58 million in field capital in 2006. These expenditures will be funded from cash flow and available bank lines. The budget was revised from the initial $70 million budget as a result of the softening in natural gas prices in the early part of 2006. It is expected that the first quarter of 2006 will be the heaviest quarter for capital spending with approximately $26 million of the total budget spent in this quarter, largely in Sylvan Lake and on tie-ins of wells drilled in the fourth quarter of 2005.

The Company's need for capital will be both short-term and long-term in nature. Short-term capital is required to finance accounts receivable and other similar short-term assets while the acquisition and development of oil and natural gas properties requires larger amounts of long-term capital. The Company increased its bank loan facility from $15 million at December 31, 2004 to $45 million at December 31, 2005. The facility will be reviewed again this spring. Anderson Energy will prudently use its bank loan facility to finance its operations as required. Anderson Energy anticipates that it will make use of equity financing for any significant expansion in its capital programs.

CRITICAL ACCOUNTING ESTIMATES

The Company's significant accounting policies are disclosed in note 1 to the consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results than reported. The Company's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results that differ materially from current estimates.

Proved Oil and Gas Reserves. Proved oil and gas reserves, as defined by the Canadian Securities Administrators in National Instrument 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering, production and any other relevant data. These estimates are subject to material change as economic conditions change and ongoing production and development activities provide new information.

An independent reserve evaluator has prepared the Company's oil and gas reserve estimate. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's development plans. The effect of changes in proved oil and gas reserves on the financial results and financial position of the Company is described below under the heading "Full Cost Accounting and Full Cost Accounting Ceiling Test".

Full Cost Accounting. The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized. The capitalized costs are depleted and depreciated using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion and depreciation. A downward revision in a reserve estimate could result in a higher depletion and depreciation charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see Full Cost Accounting Ceiling Test), the excess must be written off as an expense charged against earnings. In the event of property dispositions, proceeds are normally deducted from the full cost pool without recognition of gain or loss unless there is a change in the depletion rate of 20% or greater.

Unproved Properties. Certain costs related to unproved properties are excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted. The costs relating to unproved properties are also excluded from the book value subject to the ceiling test measurement.

Full Cost Accounting Ceiling Test. Petroleum and natural gas assets are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

Impairment is indicated if the carrying value of the oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the oil and gas assets is charged to earnings. The ceiling test is based on estimates of reserves, production rate, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Asset Retirement Obligations. The Company is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to property, plant & equipment and the appropriate liability account over the expected service life of the asset. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of economic life of the asset, costs associated with abandonment and site restoration, review of potential abandonment methods and salvage/usage of tangible equipment.

Income Taxes. The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ from that estimated and recorded by management.

Stock-Based Compensation Expense. In order to recognize stock-based compensation expense, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, volatility of the underlying security and expected dividend yields. These assumptions may vary over time.

Goodwill. The process of accounting for the purchase of a company results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise, the determination of goodwill is also imprecise. Goodwill is assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires the Company to determine the fair value of its assets and liabilities. Such a process involves considerable judgment.

BUSINESS RISKS

Oil and gas exploration and production is capital intensive and involves a number of business risks including the uncertainty of finding new reserves, the instability of commodity prices and various operational risks. Commodity prices are influenced by local and worldwide supply and demand, the U.S. dollar exchange rate, transportation costs, political stability and seasonal and weather related changes to demand. The industry is subject to extensive governmental regulation with respect to the environment.

Anderson Energy manages these risks by employing competent professional staff, following sound operating practices and using capital prudently. The Company generates its exploration prospects internally and performs extensive geological, geophysical, engineering, and environmental analysis before committing to the drilling of new prospects. Anderson Energy seeks out and employs new technologies where possible.

The Company has a formal emergency plan which details the procedures employees and contractors will follow in the event of an operational emergency. The emergency response plan is designed to respond to emergencies in an organized and timely manner so that the safety of employees, contractors, residents in the vicinity of field operations, the general public and the environment are protected. A corporate safety program covers hazard identification and control on the jobsite, establishes Company policies, rules and work procedures and outlines training requirements for employees and contract personnel.

Anderson Energy currently deals with a small number of buyers and sales contracts, and ensures those buyers are an appropriate credit risk. The Company continuously evaluates the merits of entering into fixed price or financial hedge contracts for price management.

BUSINESS PROSPECTS

The Company has an excellent drilling inventory with over five years of development drilling locations at Sylvan Lake and Sierra. The Company is in the midst of a significant drilling program at Sylvan Lake that is designed to increase production, move probable reserves to proved reserves and add additional reserves. The Company is also evaluating its coal bed methane prospective acreage with active development and exploratory drilling.

Timing of AEUB regulatory applications continues to be slower than expected. Anderson Energy has incorporated these regulatory timing issues into its planning cycle. Competition for industry services is more intense than previous years and that, combined with more landholder consultation, requires more lead time and more planning. Given the Company's extensive drilling inventory, we have been able to meet this challenge through advance planning of larger scale drilling programs and securing the services of drilling rigs and sourcing people for larger projects.

The Company has revised its 2006 average production forecast to be 5,000 to 5,400 BOED of production for 2006. Risks associated with this forecast include gas plant capacity, regulatory issues, weather problems and access to industry services.

SELECTED QUARTERLY INFORMATION

(in thousands, except per share amounts)	Q4 2005	Q3 2005	Q2 2005	Q1 2005
Oil and gas revenue before royalties	$ 22,894	$ 12,147	$ 6,646	$ 5,266
Cash flow from operations	$ 13,187	$ 6,745	$ 2,937	$ 2,580
Cash flow from operations per share				
Basic	$ 0.28	$ 0.18	$ 0.09	$ 0.08
Diluted	$ 0.27	$ 0.17	$ 0.09	$ 0.07
Earnings (loss)	$ 1,762	$ 543	$ (801)	$ (773)
Earnings (loss) per share				
Basic	$ 0.04	$ 0.01	$ (0.02)	$ (0.02)
Diluted	$ 0.04	$ 0.01	$ (0.02)	$ (0.02)
Capital expenditures	$ 25,634	$ 14,960	$ 11,589	$ 20,545
Daily sales				
Natural gas *(Mcfd)*	18,785	11,991	9,623	8,165
Liquids *(bpd)*	577	250	50	28
BOE *(BOED)*	3,708	2,249	1,653	1,389
Average prices				
Natural gas *($/Mcf)*	$ 11.39	$ 9.68	$ 7.28	$ 6.96
Liquids *($/bbls)*	$ 53.56	$ 61.97	$ 54.59	$ 52.34
BOE *($/BOE)*	$ 66.05	$ 58.49	$ 43.98	$ 41.96

	Q4 2004	Q3 2004	Q2 2004	Q1 2004
Oil and gas revenue before royalties	$ 4,170	$ 3,147	$ 4,234	$ 2,215
Cash flow from operations	$ 2,132	$ 1,369	$ 2,224	$ 491
Cash flow from operations per share				
Basic	$ 0.07	$ 0.05	$ 0.08	$ 0.02
Diluted	$ 0.07	$ 0.05	$ 0.08	$ 0.02
Earnings (loss)	$ (766)	$ (323)	$ 41	$ (569)
Earnings (loss) per share				
Basic	$ (0.03)	$ (0.01)	$ 0.00	$ (0.02)
Diluted	$ (0.03)	$ (0.01)	$ 0.00	$ (0.02)
Capital expenditures	$ 16,063	$ 14,035	$ 3,677	$ 7,592
Daily sales				
Natural gas *(Mcfd)*	6,799	5,450	6,415	3,668
Liquids *(bpd)*	25	21	22	15
BOE *(BOED)*	1,159	929	1,092	626
Average prices				
Natural gas *($/Mcf)*	$ 6.47	$ 6.08	$ 7.10	$ 6.48
Liquids *($/bbls)*	$ 51.19	$ 50.87	$ 44.46	$ 39.54
BOE *($/BOE)*	$ 39.08	$ 36.80	$ 42.62	$ 38.88

SELECTED ANNUAL INFORMATION

Years ended December 31	2005	2004	2003
Total oil and gas revenues *(thousands)*	$ 46,953	$ 13,766	$ 5,249
Total oil and gas revenues, net of royalties *(thousands)*	$ 36,780	$ 10,754	$ 3,988
Earnings (loss) *(thousands)*	$ 731	$ (1,619)	$ 318
Earnings (loss) per share (basic)	$ 0.02	$ (0.05)	$ 0.01
Earnings (loss) per share (diluted)	$ 0.02	$ (0.05)	$ 0.01
Total assets *(thousands)*	$ 269,413	$ 124,184	$ 87,222
Total long-term debt *(thousands)*	$ 11,368	$ –	$ –

Management's Report

Management is responsible for the preparation of the consolidated financial statements and the consistent presentation of all other financial information in this annual report. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes to the consolidated financial statements and in accordance with Canadian generally accepted accounting policies and include estimates and assumptions based on management's best judgement. Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner. Independent auditors appointed by the shareholders have examined the consolidated financial statements. Their report is presented below. The Audit Committee, consisting of independent members of the Board of Directors, have reviewed the consolidated financial statements with management and the independent auditors. The Board of Directors has approved the consolidated financial statements contained in this annual report on the recommendation of the Audit Committee.

Brian H. Dau
President & Chief Executive Officer

M. Darlene Wong
Vice President, Finance,
Chief Financial Officer & Secretary

March 16, 2006

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Anderson Energy Ltd. as at December 31, 2005 and 2004 and the consolidated statements of earnings (loss) and retained earnings (deficit) and cash flows for the years then ended. These consolidated financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 16, 2006

Consolidated Balance Sheets

December 31, 2005 and 2004	2005	2004
ASSETS		
Current assets:		
Cash and short-term investments	$ 510,148	$ 29,241,896
Accounts receivable and accruals	31,302,661	7,256,152
Prepaid expenses and deposits	1,562,196	276,215
	33,375,005	36,774,263
Property, plant and equipment *(note 3)*	221,717,580	87,409,900
Goodwill	14,320,159	–
	$ 269,412,744	$ 124,184,163
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accruals	$ 46,420,074	$ 20,035,430
Capital taxes payable	184,266	19,916
	46,604,340	20,055,346
Bank loan *(note 5)*	11,368,057	–
Asset retirement obligations *(note 4)*	11,298,644	2,093,758
Future income taxes *(note 7)*	16,073,201	727,452
	85,344,242	22,876,556
Shareholders' equity:		
Share capital *(note 6)*	184,315,159	102,388,612
Contributed surplus *(note 6)*	102,963	–
Deficit	(349,620)	(1,081,005)
	184,068,502	101,307,607
	$ 269,412,744	$ 124,184,163

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Director

J.C. Anderson

Director

Consolidated Statements of Earnings (Loss) and Retained Earnings (Deficit)

Years ended December 31, 2005 and 2004	2005	2004
REVENUES		
Oil and gas sales	$ 46,952,610	$ 13,765,615
Royalties (net of ARTC of $500,000 in 2005, $235,546 in 2004)	(10,172,752)	(3,012,013)
Interest income	279,210	557,669
	37,059,068	11,311,271
EXPENSES		
Operating	7,479,965	2,736,325
General and administrative	3,741,557	2,231,350
Interest and other financing charges	203,496	49,717
Depletion, depreciation and accretion	23,570,238	8,469,998
	34,995,256	13,487,390
Earnings (loss) before taxes	2,063,812	(2,176,119)
Taxes *(note 7)*		
Capital taxes	282,427	77,549
Future income taxes (reduction)	1,050,000	(635,000)
	1,332,427	(557,451)
Earnings (loss) for the year	731,385	(1,618,668)
Retained earnings (deficit), beginning of year	(1,081,005)	537,663
Deficit, end of year	$ (349,620)	$ (1,081,005)
Earnings (loss) per share		
Basic	$ 0.02	$ (0.05)
Diluted	$ 0.02	$ (0.05)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

Years ended December 31, 2005 and 2004	2005	2004
CASH PROVIDED BY (USED IN):		
OPERATIONS		
Earnings (loss) for the year	$ 731,385	$ (1,618,668)
Items not involving cash		
Depletion, depreciation and accretion	23,570,238	8,469,998
Future income taxes (reduction)	1,050,000	(635,000)
Stock-based compensation	102,963	–
Asset retirement expenditures	(310,466)	–
Changes in non-cash working capital		
Accounts receivable and accruals	(3,369,946)	(1,655,330)
Prepaid expenses and deposits	(311,538)	(18,188)
Accounts payable and accruals	3,805,926	1,704,314
Capital taxes payable	164,350	(155,446)
	25,432,912	6,091,680
FINANCING		
Increase in bank loan	11,368,057	–
Issue of common shares	30,411,624	22,800,257
	41,779,681	22,800,257
INVESTMENTS		
Additions to property, plant and equipment	(70,516,760)	(41,421,582)
Proceeds on sale of properties	1,125,000	930,473
Acquisition of Aquest Energy *(note 2)*	(1,041,773)	–
Payment of Aquest Energy liabilities assumed *(note 2)*	(26,438,520)	–
Changes in non-cash working capital		
Accounts receivable and accruals	(20,676,563)	(3,903,891)
Prepaid expenses and deposits	(974,443)	256,201
Accounts payable and accruals	22,578,718	13,906,110
	(95,944,341)	(30,232,689)
Decrease in cash and short-term investments	(28,731,748)	(1,340,752)
Cash and short-term investments, beginning of year	29,241,896	30,582,648
Cash and short-term investments, end of year	$ 510,148	$ 29,241,896

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended December 31, 2005 and 2004

Anderson Energy Ltd. ("Anderson Energy" or "the Company") was incorporated under the laws of the province of Alberta on January 30, 2002. Anderson Energy is engaged in the acquisition, exploration and development of oil and gas properties in western Canada. These consolidated financial statements include the accounts of Anderson Energy Ltd. and its wholly owned subsidiaries and have been prepared by management in accordance with accounting principles generally accepted in Canada. Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenue and expenses during the reported period. Actual results could differ from these estimates.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) *Cash and short-term investments.* Cash and short-term investments are defined as cash in the bank, less outstanding cheques, and short-term investments. Short-term investments have a maturity of three months or less.

(b) *Capital assets.* The Company follows the full cost method of accounting for oil and gas properties. Under this method, all costs relative to the exploration for and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, geological and geophysical costs, lease rentals on non-producing properties, costs of drilling productive and non-productive wells and plant and production equipment costs. Proceeds received from disposals of oil and gas properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20%, in which case a gain or loss on disposal is recorded.

Oil and gas capitalized costs are depleted and depreciated using the unit of production method based on total proved reserves before royalties. Natural gas sales and reserves are converted to equivalent units of crude oil using their relative energy content. The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the property or impairment occurs. Office equipment and furniture are being depreciated over their useful lives using the declining balance method at rates between 20% and 30% per annum.

A detailed impairment calculation is performed when events or circumstances indicate a potential impairment of the carrying amount of oil and gas assets may have occurred, and at least annually. An impairment loss is recognized when the carrying amount of a cost centre is not recoverable and exceeds its fair value. The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the proved reserves plus the cost of unproved interests, net of impairments, exceeds the carrying amount of the cost centre. When the carrying amount is assessed not to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the

sum of the discounted cash flows from proved and probable reserves plus the cost of unproved interests, net of impairments, of the cost centre. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(c) *Asset retirement obligations.* The Company records the fair value of asset retirement obligations as a liability in the period in which it incurs a legal obligation to restore an oil and gas property, typically when a well is drilled or equipment is put in place. The associated asset retirement costs are capitalized as part of the carrying amount of capital assets and depleted and depreciated using the unit of production method based on total proved reserves before royalties. Subsequent to the initial measurement of the obligations, the obligations are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

(d) *Goodwill.* Goodwill is the excess purchase price over the fair value of identifiable assets and liabilities acquired in a business combination. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. To assess impairment, the fair value of the Company is determined and compared to the book value of the Company. If the fair value of the Company is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the individual assets and liabilities from the fair value of the Company to determine the implied fair value of goodwill. An impairment loss is recognized for the excess of the carrying value of goodwill over the implied fair value.

(e) *Income taxes.* The Company follows the asset and liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using income tax rates enacted at the balance sheet date. The effect of a change in rates on future income tax assets and liabilities is recognized in the period that the change occurs.

(f) *Flow-through shares.* The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. An estimate of the additional tax liability to be incurred and included in the future tax provision is recognized and charged to share capital at the time the resource expenditure deductions for income tax purposes are renounced to investors.

(g) *Stock-based compensation plans.* The Company accounts for stock options granted to employees and directors using the fair value method of accounting for stock-based compensation plans. Under this method, the Company recognizes compensation expense, with a corresponding increase to contributed surplus, based on the fair value of the options over the vesting period of the grant. The Company uses a Black-Scholes option pricing model to determine the fair value of options at the date of grant. When exercised, the consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(h) *Revenue recognition.* Revenue from the sale of oil and gas is recognized when title passes from the Company to the purchaser.

(i) *Interests in joint ventures.* A substantial portion of the Company's oil and gas exploration and development activities are conducted jointly with others, and accordingly, the consolidated financial statements reflect only the Company's proportionate interest in such activities.

(j) *Per share amounts.* Basic per share amounts are calculated using the weighted average number of common shares outstanding during the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only options for which the exercise price is less than the market value impact the dilution calculations.

2. *ACQUISITION OF AQUEST ENERGY LTD.*

On June 27, 2005, the Company entered into an arrangement agreement with Aquest Energy Ltd. ("Aquest Energy"), a publicly traded oil and gas company. Pursuant to the arrangement, Anderson Energy acquired all of the outstanding shares of Aquest Energy for consideration of 0.31 Anderson Energy shares for each Aquest Energy share, for total consideration of 9.6 million Anderson Energy common shares valued at $53.1 million before transaction costs. The arrangement was approved by the shareholders and received regulatory approval on August 31, 2005 and the transaction closed on September 1, 2005. The acquisition has been accounted for using the purchase method of accounting whereby the assets and liabilities of Aquest Energy were recorded at fair market values at September 1, 2005 and the operating results were included in the consolidated financial statements from September 1, 2005. The fair value of the assets acquired and the liabilities assumed on September 1, 2005 are as follows:

Current assets	$ 8,381,468
Bank loan	(20,946,536)
Accounts payable and accruals	(13,873,452)
Property, plant and equipment	84,793,295
Goodwill	14,320,159
Asset retirement obligations	(5,822,489)
Future income taxes	(12,701,864)
	$ 54,150,581
Consideration paid:	
9,656,147 common shares	$ 53,108,808
Transaction costs	1,041,773
	$ 54,150,581

3. *PROPERTY, PLANT AND EQUIPMENT*

	2005	2004
Cost	$ 255,289,421	$ 97,766,376
Less accumulated depletion and depreciation	(33,571,841)	(10,356,476)
Net book value	$ 221,717,580	$ 87,409,900

At December 31, 2005, unproved property costs of $22.6 million (December 31, 2004 – $14.7 million) have been excluded from the full cost pool for depletion and depreciation calculations. Future development costs of proved, undeveloped reserves of $73.5 million (December 31, 2004 – $5.6 million) have been included for depletion, depreciation and impairment test calculations.

For the year ended December 31, 2005, $1.7 million (2004 – $0.7 million) of general and administrative costs were capitalized. Capitalized general and administrative costs consist of salaries and associated office rent of staff involved in capital activities.

No impairment was recognized under the ceiling test at December 31, 2005. The future commodity prices used in the ceiling test were based on commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The natural gas price at AECO was estimated to be $11.50 per thousand cubic feet in 2006, $10.50 in 2007, $8.90 in 2008, $8.50 in 2009, $8.70 in 2010 and $8.90 in 2011. After 2011, only inflationary growth was considered. Natural gas liquids prices were tied to crude oil prices based on historical trends and analysis. The WTI crude oil price was forecast to be US$60.00 per barrel in 2006, US$61.20 in 2007, US$62.45 in 2008, US$61.60 in 2009, US$59.55 in 2010 and US$55.15 in 2011. After 2011, only inflationary growth was considered.

4. ASSET RETIREMENT OBLIGATIONS

The Company estimates the total undiscounted cash flows required to settle its asset retirement obligations is approximately $15.1 million, including expected inflation of 2% per annum. The majority of the costs will be incurred between 2006 and 2016. A credit adjusted risk-free rate of 7.5% was used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	2005	2004
Balance, beginning of year	$ 2,093,758	$ 1,133,068
Liabilities incurred during period	3,337,990	876,148
Liabilities assumed on Aquest Energy acquisition	5,822,489	–
Liabilities settled in year	(310,466)	–
Accretion expense	354,873	84,542
	$ 11,298,644	$ 2,093,758

5. BANK LOAN

In June 2005, the Company renewed its revolving credit facility with a Canadian Bank, increasing the borrowing base to $45 million. The reserve-based credit facility has a 364 day revolving period, extendible at the option of the lender, followed by a 180 day term period. Advances under the facility can be drawn in either Canadian or U.S. funds. The facility bears interest at the bank's prime lending rate, bankers' acceptance or LIBOR loan rates plus applicable margins. The margins vary depending on the borrowing option used and the Company's financial ratios. Loans are secured by a floating charge debenture over all assets and guarantees by material subsidiaries.

On December 31, 2005, the Company had outstanding letters of credit in the amount of $717,500 related to operations.

6. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized share capital. On September 1, 2005, the Company filed articles of amendments to create an unlimited number of common shares and delete the existing Class A and Class B shares from the authorized share capital.

The Company is authorized to issue an unlimited number of preferred shares. The preferred shares may be issued in one or more series.

Issued share capital.

	Number Class A	Number Class B	Common shares	Amount
Balance at December 31, 2003	875,000	28,541,667	–	$ 79,117,460
Issued for cash pursuant to private placement (1)	–	3,278,000	–	18,029,000
Issued for cash pursuant to flow-through share arrangements (1)	–	870,000	–	6,003,000
Share issue costs	–	–	–	(1,231,743)
Future tax effect of share issue costs	–	–	–	470,895
Balance at December 31, 2004	875,000	32,689,667	–	102,388,612
Stock options exercised	–	60,000	–	240,000
Tax effect of flow-through share renouncements	–	–	–	(2,293,146)
Conversion to common shares	(875,000)	(32,749,667)	33,624,667	–
	–	–	33,624,667	100,335,466
Issued on Aquest Energy acquisition			9,656,147	53,108,808
Issue of common shares (2)			3,100,000	20,150,000
Issue of flow-through common shares (2)			1,250,000	10,000,000
Share issue costs			–	(1,830,524)
Future tax effect of share issue costs			–	699,261
Stock options exercised			336,894	1,852,148
Balance at December 31, 2005			47,967,708	$ 184,315,159

(1) Includes 284,300 common shares and 142,750 flow-through shares issued to management, directors and employees

(2) Includes 7,000 common shares and 6,000 flow-through shares issued to a director

Pursuant to the plan of arrangement each Class A and B shareholder received one common share for each Class A or B share held.

Flow-through shares. Under flow-through share agreements entered into in 2004, the Company committed to incur $6,003,000 of qualifying expenditures by December 31, 2005. The renouncements were made on February 28, 2005 with an effective date of December 31, 2004.

Under flow-through share agreements entered into in 2005, the Company committed to incur $10,000,000 of qualifying expenditures by December 31, 2006. The renouncements were made on February 28, 2006 with an effective date of December 31, 2005.

Stock option plan. The Company has an employee stock option plan under which employees, directors and consultants are eligible to receive grants. Changes in the number of options outstanding during the year ended December 31, 2005 are as follows:

Balance at December 31, 2003	3,058,000
Granted	373,200
Expirations and cancellations	(19,500)
Balance at December 31, 2004	3,411,700
Granted	961,465
Assumed on the acquisition of Aquest Energy	964,300
Exercised	(396,894)
Expirations and cancellations	(761,216)
Balance at December 31, 2005	4,179,355

The outstanding options at December 31, 2005 had an average exercise price of $4.95 and a weighted average remaining contractual life of six years; 3,025,822 of the options were exercisable at that date.

On January 1, 2005, the Company adopted the fair value method of accounting for stock-based compensation plans. Under this method, the Company recognizes compensation expense, with a corresponding increase to contributed surplus, based on the fair value of the options over the vesting period of the grant. The application of this method of accounting for stock-based compensation plans would have resulted in negligible compensation expense being recorded in years prior to 2005 as the exercise price of the options was significantly higher than the fair value of the underlying stock at the date of the grant.

The weighted average fair value of the options issued in 2005 was $2.00 per option. The weighted average assumptions used in arriving at these values were: a risk-free interest rate of 3.3%, expected option life of four years, expected volatility of 25% and a dividend yield of 0%.

Per share amounts. During the year ended December 31, 2005, there were 38,371,995 weighted average shares outstanding (2004 – 29,535,834). On a diluted basis, there were 39,309,036 weighted average shares outstanding (2004 – 29,976,506) after giving effect to dilutive stock options.

Contributed surplus.

		Amount
Balance at December 31, 2004	$	–
Stock-based compensation		102,963
Balance at December 31, 2005	$	102,963

7. *TAXES*

The temporary differences that gave rise to the Company's future income tax liabilities (assets) were as follows.

	2005	2004
Future income tax liabilities (assets):		
Property, plant and equipment in excess of tax basis	$ 16,826,501	$ 2,001,231
Asset retirement obligation	(3,821,201)	(820,327)
Share issue expenses	(1,216,375)	(453,452)
Current income deferred	4,284,276	–
	$ 16,073,201	$ 727,452

The provision for income taxes differs from the result that would have been obtained by applying the combined federal and provincial tax rates to earnings before income taxes. The difference results from the following items:

	2005	2004
Earnings (loss) before income tax	$ 2,063,812	$ (2,176,119)
Combined federal and provincial tax rates	37.92%	39.74%
Expected income tax expense (recovery)	782,597	(864,790)
Increase (decrease) in income taxes resulting from:		
Non-deductible crown payments	1,457,986	685,606
Federal resource allowance	(1,036,516)	(466,390)
Capital taxes	282,427	77,549
Changes in expected future tax rates and other	(154,067)	10,574
Provision for (recovery of) income taxes	$ 1,332,427	$ (557,451)

8. *CASH PAYMENTS*

The following cash payments were received (paid):

	2005	2004
Interest received	$ 308,785	$ 601,735
Interest paid	(231,463)	(49,717)
Taxes paid	(118,077)	(330,446)
	$ (40,755)	$ 221,572

9. *FINANCIAL INSTRUMENTS*

The carrying value of financial instruments included in the consolidated balance sheets approximate their fair value. Financial instruments include cash and short-term investments, accounts receivable, deposits, accounts payable and accruals, capital taxes payable and bank loans. The carrying value of

accounts receivable and accruals, deposits and accounts payable and accruals approximate their fair value due to their demand nature or relatively short periods to maturity. The fair value of the bank loan approximates its carrying value as it bears interest at a floating rate.

Cash and short-term investments are subject to fluctuations in short-term Canadian interest rates. Short-term investments are in a cash management fund consisting of short-term government guaranteed and bank securities and do not expose the Company to unusual credit risk.

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas and liquids are subject to internal credit review to minimize the risk of non-payment.

The Company is exposed to foreign currency fluctuations as natural gas and liquids prices received are referenced to United States dollar denominated prices. At December 31, 2005, the Company does not have any forward or futures contracts for the sale of its production.

10. RELATED PARTY TRANSACTIONS

At December 31, 2005, accounts payable include $304,000 due to companies controlled by a director of the Company. The director was previously a director of Aquest Energy and the amounts arise as a result of common joint venture interests held by the director and Aquest Energy which was acquired by the Company. The transactions have been recorded under the same terms and conditions as transactions with unrelated parties.

In February 2006, the Company issued 576,394 common shares at an average price of $7.74 per share as consideration for the purchase of oil and gas properties. The aggregate purchase price of the assets acquired in the five separate transactions was $4.5 million. Two of the transactions were with companies controlled by the director noted above for total consideration of 224,660 shares at an average price of $7.81 per share or $1.8 million. The two transactions were completed under the same terms and conditions as the other transactions.

11. COMMITMENTS

The Company has entered into an agreement to lease office space until November 2008. Future minimum lease payments are expected to be $801,175 in 2006, $745,430 in 2007 and $683,312 in 2008.

The Company has entered into a one year firm service gas gathering and treatment contract in northeast B.C. commencing in April 2005 for approximately two million cubic feet per day of raw contract demand. The take or pay payments under this contract are expected to be $146,852 in 2006.

12. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

Creating success together.

In recognition of the managers who are contributing to our success.

Jamie Marshall
Manager, Exploration
Department Head

Phil Hyde
Manager, Production

Rob Kay
Manager, Drilling & Completions

Monique Lemoine
Manager, Administration

Steve Smith
Chief Geophysicist

Denis Tremblay
Manager, Accounting

Barry Weeks
Manager, Development Geology

Corporate Information

DIRECTORS

J.C. Anderson
Calgary, Alberta

Brian H. Dau
Calgary, Alberta

Vincent L. Chahley (1) (2)
Calgary, Alberta

Glenn D. Hockley (2)
Calgary, Alberta

David G. Scobie (1) (2)
Calgary, Alberta

R.T. (Tim) Swinton (1)
Calgary, Alberta

(1) Member of Audit Committee and Compensation and Corporate Governance Committee
(2) Member of Reserves Committee

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Abbreviations Used:

bbls	*barrels*
bpd	*barrels per day*
Mbbls	*thousand barrels*
BOE	*barrels of oil equivalent*
BOED	*barrels of oil equivalent per day*
MBOE	*thousand barrels of oil equivalent*
MMBOE	*million barrels of oil equivalent*
Mcf	*thousand cubic feet*
Mcfd	*thousand cubic feet per day*
MMcf	*million cubic feet*
MMcfd	*million cubic feet per day*
Bcf	*billion cubic feet*
GJ	*gigajoule*
Btu/scf	*British thermal unit per standard cubic foot of gas*

OFFICERS

J.C. Anderson
Chairman of the Board

Brian H. Dau
President & Chief Executive Officer

M. Darlene Wong
Vice President Finance,
Chief Financial Officer & Secretary

Blaine M. Chicoine
Vice President, Operations

Philip A. Harvey
Vice President, Exploitation

Daniel F. Kell
Vice President, Land

David M. Spyker
Vice President, Business Development

AUDITORS

KPMG LLP
Calgary, Alberta

INDEPENDENT ENGINEERS

AJM Petroleum Consultants

LEGAL COUNSEL

Bennett Jones LLP

REGISTRAR & TRANSFER AGENT

Valiant Trust Company

STOCK EXCHANGE

The Toronto Stock Exchange
Symbol: AXL

BACK COVER:

DAVID G. SCOBIE *Director*

BLAINE M. CHICOINE *Vice President, Operations*

DANIEL F. KELL *Vice President, Land*

INSIDE BACK COVER:

GLENN D. HOCKLEY *Director*

PHILIP A. HARVEY *Vice President, Exploitation*

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